INSTITUT C.D. HOWE INSTITUTE

COMMENTARY
NO. 389

A New Blueprint for Ontario's Electricity Market

Ontario can more cost-effectively meet its electricity needs and environmental objectives by returning to reliance on a well-designed market, with truly independent institutions and long-term price signals for new capacity on a technology-neutral basis.

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Commentary No. 389
September 2013
Energy/Infrastructure and Environment

Finn Poschmann
Vice-President, Research

$12.00
ISBN 978-0-88806-910-8
ISSN 0824-8001 (print);
ISSN 1703-0765 (online)

The Study In Brief

An ongoing challenge for power markets worldwide is to assure sufficient continued investment to maintain reliability. A properly designed capacity market – in which plants receive payment for available supply capacity whether or not the power generator runs – may enable Ontario to increase reliance on market signals for new investment. To be effective, the government must pair building a capacity market with several changes in the role and function of existing Ontario power market institutions. The government should isolate policymakers from implementation agencies.

The Ontario power sector today has oversupply, a mismatch of generator capabilities and needs, rising prices to final consumers, a lack of transparency in prices, and volatile and contradictory policies. Consequently, private-sector actors are unable to justify investment without some form of government-backed contract. The government's failure to rely on either sound planning or market principles has meant that the province has not procured generation capacity at a long-run least cost.

Current surplus supply conditions provide a window for thoughtful policy review. The government should establish a market that sends transparent and effective price signals of the need for new electricity generation capacity. Doing so first requires creating appropriate buffers between implementation entities and policymakers, meaning that the government should not use ministerial directives to interfere with the day-to-day operation of key power sector institutions. It also requires that the province replace the Ontario Power Authority's principal buyer role with newly created supply entities.

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Ontario's electricity system operates on a framework constructed haphazardly to satisfy often-contradictory public policy goals. The result is a litany of inefficiencies.

The province's power sector today has an electricity oversupply, a mismatch between generator capabilities and supply needs, rising prices for final consumers and a lack of cost transparency, along with a record of volatile, often contradictory, policies. Consequently, private-sector electricity generators are unable to justify investment in the system without some form of government-backed contract.

While various provincial governments have announced laudable goals over the years, their failure to implement either sound planning or rely on market principles has meant that Ontarians are not getting electricity at the lowest possible cost. Projections suggest that Ontario residents and businesses will be paying substantially higher electrical bills over the next decade than if the provincial electricity system had instead relied on combined cycle natural gas turbine electricity generation,[1] even when the potential costs of buying greenhouse gas emissions credits are taken into account. As well, Ontario's Feed-in Tariff program, under which the province has contracted for extensive wind and solar power for some years into the future, will increase generation and transmission costs, further hiking electricity prices.

Meanwhile, the development of low-cost shale gas in North America has meant that the economics of natural gas-fired electricity plants, and combined cycle plants in particular, have changed dramatically. The province should redesign its electricity generation procurement to incorporate market signals that would attract long term least-cost generation sources while avoiding the procurement mistakes of the past.

In future, Ontario's electricity generation procurement should become technologically neutral to ensure that the province builds the most cost-effective, environmentally compliant generation assets. The province should accompany this procurement policy shift with changes in the role of existing Ontario power market institutions, as well as a framework to isolate policymakers from implementation agencies. History has proven that unless institutions are autonomous, politicians often succumb to the temptation to circumvent electricity sector policymaking processes.

The author would like to thank Kelima Yakupova, Victor Chung, Bat-Erdene Baatar and Robert Delaney of London Economics International. Many reviewers provided useful comments, including Timothy Brennan, Jan Carr, Don Dewees, Roy Hrab, Brian Rivard, Michael Trebilcock, Michael Wyman, Mel Ydreos, as well as others who wish to remain anonymous. A more extersive version of this paper can be found at www.londoneconomics.com.

Mr. Goulding advises a range of public and private clients in Ontario on issues associated with market design, asset valuation, and regulatory economics. Calculations produced for the purposes of this paper are purely illustrative; additional analysis would be required for any such calculations to be cited in legal or regulatory proceedings. Given the conceptual nature of this paper, discussions of individual elements are not intended to be comprehensive or exhaustive. Findings in this paper should in no way be construed as suggesting that the author supports the establishment of capacity markets in all jurisdictions or under any circumstances.

1 Combined cycle natural gas-fired turbine electricity generation combines a natural gas-fired electricity-generating turbine (the first stage) with the exhaust heat used to create steam to power a second electricity-generating turbine.

Establishing an Ontario capacity market would enable the province to increase reliance on market signals for new investment. To be efficient, this market would need an appropriate number of sellers and buyers. An important step in creating more of these counterparties is to increase the number of entities with a direct responsibility for serving the end customers. Such load-serving entities would be responsible for providing customers with the commodity portion of their load, as distinct from its transportation of it.

Currently, Ontario's Feed-in Tariff program and nuclear power programs serve narrow policy objectives, which have made their underlying generation assets more expensive than natural gas, even if a substantial price is placed on greenhouse gas emissions. To address greenhouse gas concerns, the most sensible answer is a North American cap-and-trade mechanism, which would yield additional revenue for the province through emission credit auctions.

Ontario's principal buyer-based capacity procurement is neither a planned nor a market approach, though it inflicts the worst aspects of both on ratepayers. It has resulted not only in cost impacts for the province's consumers, favouring generation technologies that don't necessarily produce the most efficient reductions in greenhouse gas emissions, but also in a surplus of generation capacity. Policymakers should capitalize on this period of surplus as it offers the government a window for thoughtful policy review.

Part 1: Problems with the Status Quo

Ontario's approach to power sector investment and planning is inefficient, expensive and arguably unsustainable. Investment decisions reflect neither market signals nor long-term, centralized, utility-style system plans. The government is using the electricity sector to support a range of shifting policy objectives, including job creation, sector-specific economic growth and emissions reduction, without credible examination of whether burdening the electricity ratepayer with the cost of such initiatives is economically efficient.

As well, Ontario has failed to insulate electricity institutions (see Box 1) from ad hoc policy changes, which have proven costly to consumers while undermining democratic principles of openness and public participation. No political party has a monopoly on political interference in the power sector in Ontario. All have engaged in ill-considered price freezes and reductions, sudden policy shifts and stopgap solutions.

The Costs of Today's Electricity System

While often characterized as "hybrid," Ontario's electricity market largely consists of a principal buyer, the Ontario Power Authority (OPA), whose decisions are heavily influenced by the provincial government. Investors have been wary about building generation capacity without an OPA contract.

Despite limited or negative electricity demand growth over the past five years (2007-2011 inclusive), averaging minus 1.1 percent per year, Ontario's installed capacity has grown over the same period by 1.8 percent annually. While a portion of this capacity increase has been justified by the decision to close all of Ontario's coal-fired power stations, current policies could result in excess supply relative to peak demand through 2019 (Figure 2).[2]

2 The graphic shows only capacity currently under contract; it does not account for further capacity to be added under the ongoing FIT program.

Box 1: Current Ontario Electricity Market Arrangements

The provincially owned Ontario Power Generation (OPG) is the province's dominant electricity supplier, with its nuclear and hydroelectric rate-regulated (also known as "prescribed") power plants providing nearly one-half of Ontario's power output (Figure 1). OPG's role, however, has diminished recently as the Ontario Power Authority (OPA), which has overall responsibility for ensuring the province's long-term electricity supply, contracted with new entrants such as solar and wind power producers using a Feed-in Tariff (FIT). OPG also has some unregulated power generating assets that operate on a merchant basis. Bruce Power operates the Bruce Nuclear Generating Station, leased from OPG, with a generating contract with the OPA. The Ontario Electricity Financial Corporation (OEFC) holds contracts with private generators built before the dissolution of Ontario Hydro.

Although OPA nominally bases its contracting decisions on its Long-term Energy Plan (LTEP), provisions of the Ontario *Green Energy Act* (GEA) and subsequent ministerial directives have overridden the LTEP. In spring 2013, the Ontario Minister of Energy announced a formal LTEP review to update long-term supply and demand forecasts, focusing on diversity of supply mix, conservation and creation of a predictable and sustainable clean-energy procurement process.

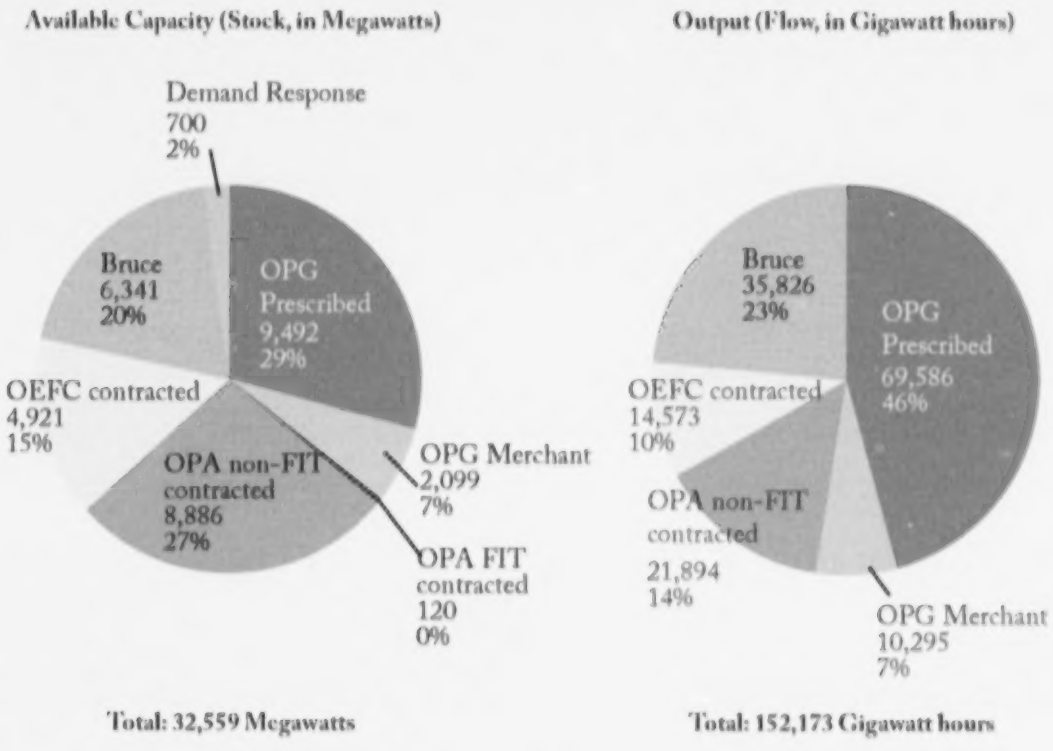
The Ontario Independent Electricity System Operator (IESO) coordinates dispatch and transmission flows and operates spot markets. The Ontario Energy Board (OEB) regulates a portion of OPG's generation capacity, but otherwise has limited oversight of generation markets and the OPA.

A large portion of wholesale energy costs are recouped through the Global Adjustment (GA). The GA is paid by electricity consumers, and was established as a so-called Provincial Benefit, separate from the Debt Retirement Charge (DRC). The DRC consists mainly of payments on outstanding Ontario Hydro debt that successor companies were unable to absorb. With the OPA's creation, the GA came to include the costs of OPA contracts that it cannot recover through market revenues. In 2012, more than one-half (54 percent) of the cost of the GA was comprised of OPA charges on contracts for generators and suppliers of conservation services, while charges on OPG's nuclear and baseload hydroelectric generation (29 percent) and the contracts held by the OEFC (17 percent) made up the remainder (IESO N.D.). Changes in IESO prices and the level of the Global Adjustment are largely symmetrical because, in order to fulfill the terms of the contracts it holds that guarantee generators a certain amount of revenue, OPA payments to generators fall, or become negative, as IESO prices approach or exceed the contract price.

Under the *Ontario Energy Board Act*, the OEB can review only OPA activities related to conservation targets and payments to and from distributors, retailers or the IESO. The OPA is required to assist the OEB by facilitating stability in rates for certain types of customers and provide information relating to medium- and long-term electricity needs, as well as the adequacy and reliability of the province's power systems. OEB also approves OPA's electricity procurement process and its annual fees.

The total cost of electricity for Ontario consumers is the sum of the Hourly Ontario Electricity Price (HOEP) and the Global Adjustment (GA). It is useful to examine this total cost from two perspectives: first, in comparison with adjacent markets over the recent past, and in comparison with the future projected all-in cost of a new, generic natural gas-fired combined cycle gas turbine (CCGT). Total energy costs to Ontario consumers have been higher than those in neighbouring western New York state despite falling natural gas prices in both jurisdictions (Figure 3).

Figure 1: 2012 Ontario Available Capacity and Output by Asset Type



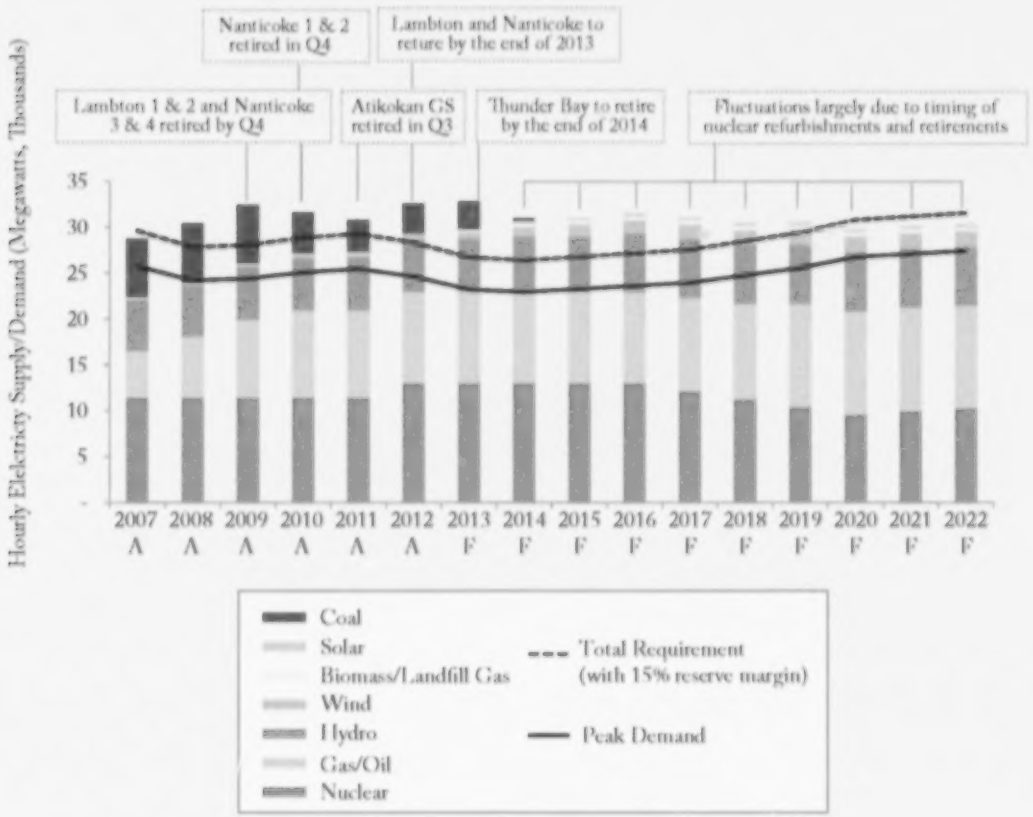
Note: Wind capacity is derated to 23.5% of installed capacity (average of 13.4% in summer and 33.6% in winter), and capacity for solar is de-rated to 20% (average of 40% in summer and 0% in winter), as reported in NERC (2011). Capacity for hydroelectric resources is de-rated to 72% (average of 67% and 77% range of contribution factors used by IESO 2012a). As of December 31, 2012, OPA reports 501 MW of in-service FIT and micro FIT capacity (solar, wind and biomass) which, after applying de-rates, translates into 120 MW of available capacity.

Sources: London Economics International (LEI) calculations from Energy Velocity commercial database; OPA (2012a,b); and IESO (2012a,b).

Cost Impacts

Natural gas plants serve as the price-setting electricity generator in most North American electricity markets. Western New York's all-in prices are more rapidly allowing customers to benefit from declines in natural gas prices, while Ontario's all-in prices are not. Looking forward, projections suggest that Ontario will be paying substantially more over the next decade than the cost of a combined cycle gas turbine that provides baseload power, even when taking into account carbon costs (Figure 4). In other words, had different policies been pursued, Ontario could have had both low-emission electricity – relative to coal power – and lower prices than currently prevail by allowing natural gas to play an even more prominent role in Ontario's fuel mix.

Figure 2: Ontario Supply-demand Balance 2007 to 2022



Notes: A: Actual data. F: Forecast. Calculations include the expected additional capacity currently under contract. Capacity for wind, solar and hydroelectric resources treated in the same fashion as for Figure 1. OPA contracted supply is as of December 31, 2012. OPA reports 2,019 MW in-service wind capacity and 3,772 MW under construction expected to come online by the end of 2015; with de-rate factor of 23.5 percent this translates into 474 MW in 2012 and 887 MW of additional wind by the end of 2015. Figure includes OPA RESOP solar contracts and IESO reported actual capacity. IESO (2012a) suggests average reserve margin target of 18.7 percent, the 15 percent reserve margin assumes that interconnections contribute to reliability. Sources: LEI calculations from IESO historical data; IESO (2012b); OPA (2012a,b,c).

The Ontario power market lacks both the clarity of a disciplined integrated resource plan and the benefits of competitive pressure on generators. In a fully regulated market, the utility would submit a procurement plan to its regulator that would be vetted in an open process. Upon approval, the utility would be charged with implementing the plan at least cost.

As it is, Ministerial directives that OPA secure electricity contracts in particular ways constantly

Figure 3: Five-year Comparison of Ontario Electricity Prices to Western New York Electricity Prices and Natural Gas Prices

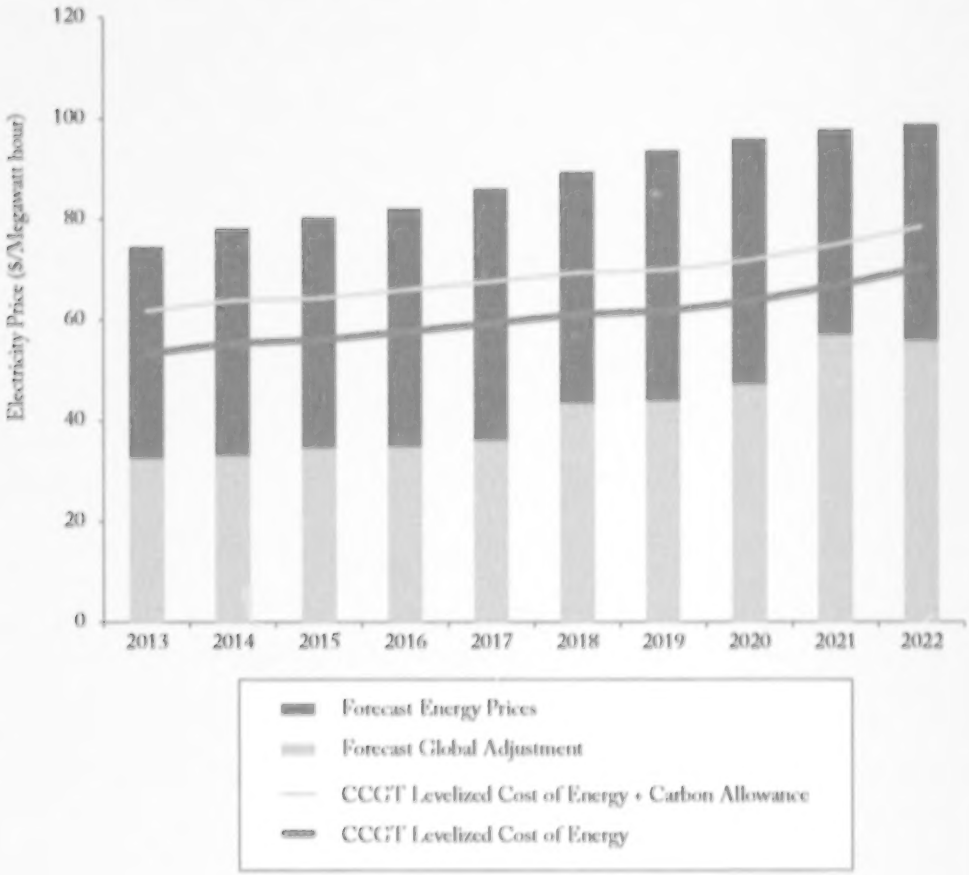
Note: Ontario prices include HOEP and GA. Western New York electricity price includes energy, capacity and System Benefit Charge (the System Benefit Charge pays for various policy initiatives consistent with some aspects of the GEA). Competitive transition charges (CTCs) in Western New York were eliminated in January 2012 and are excluded from the chart; all figures in nominal Canadian dollars, using Bloomberg historical monthly exchange rates. The Dawn Hub price is a standard benchmark of Canadian natural gas prices, the Henry Hub price is a major benchmark for US natural gas prices.

Source: LEI calculations from IESO; OPA; New York Independent System Operator; Bloomberg.

modify previously approved long-term plans.[3] Between 2005 and June 2013, the Minister of Energy issued 66 directives to OPA. Out of these, 36 directed OPA with relation to procurement of power/capacity from OPG or other generators.

3 FIT Program Version 2.0 (effective since Aug. 10, 2012) rules improved on previous arrangements by including a procurement targets provision establishing the maximum amount of MWs procured during an application period; OPA will procure up to 200 MW worth of contracts (the procurement target) during the Small FIT application window (Dec. 14, 2012 – Jan. 18, 2013). An additional 15 MW is set aside for pilot rooftop solar projects (See OPA 2012d, OPA N.D.a, OPA N.D.b and OPA 2012e).

Figure 4: Comparison of Estimated Ontario Electricity Price Levelized Cost of Natural Gas CCGT

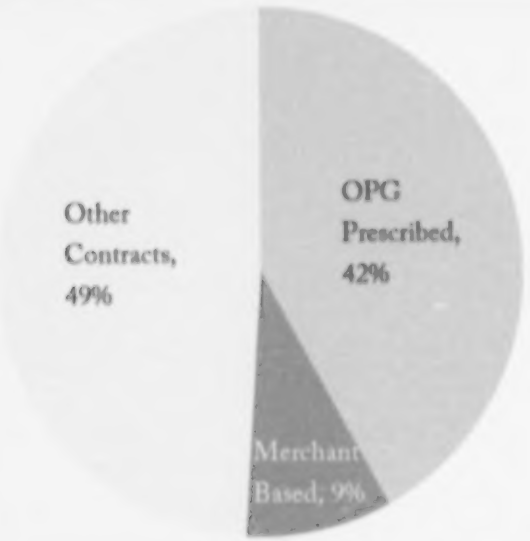


Note: CCGT capacity factor assumed to be 85 percent; gas prices are NYMEX Henry Hub forwards as of mid-October 2012 escalated toward the Energy Information Administration (2012) projected 2020 gas price, plus the 5-year (2007-2011) average differential between annual Henry Hub and Dawn prices; carbon allowance price assumed to be $20/ton; all figures nominal Canadian dollars and assuming exchange rate CA $1/US$. The CCGT capacity factor assumes a unit is added to the system when it is efficient to do so, rather than current actual capacity factors of underutilized existing plants. CCGT capacity factors averaged 26% in Ontario in 2012, according to a commercially-available database. Underutilized gas plants further highlight the extent to which supply and demand have been mis-matched in Ontario.

Sources: LEI calculations from IESO; OPA; EIA.

Meanwhile, the government has banished the word "market" from the Independent Electricity System Operator's (IESO) name, and 91 percent of the province's energy production is either under contract to the OPA or rate-regulated by OEB (Figure 5), few plants rely solely on IESO-run markets, because most earn revenue through OPA contracts.

Figure 5: Expected Breakdown of Ontario 2013 Generation Based on Contractual Position



Source: OEB (2013a, p. 21).

Ontario's failure to implement either a planned or a market approach for the power sector has resulted in higher costs for provincial consumers. This failure has also produced a surplus of generation capacity, with Ontario consumers liable to pay an additional $42 million to $370 million per year beyond what is required to meet a 15 percent reserve margin between 2013 and 2015.[4] The actual costs to Ontario consumers may be end up being higher than $370 million, given that the OPA has reported significantly higher capacity costs for recently constructed plants.[5]

Similarly, the Auditor General of Ontario has stated that the FIT program causes higher prices and added about $4.4 billion in costs over its 20-year contract terms compared to what would have been incurred under the previous, less-generous Renewable Energy Standard Offer Program. (Office of the Auditor General of Ontario 2011). The FIT program offered guaranteed prices for renewable projects under 10 MW until Ontario's Ministry of Energy put the program under review.

Other costs resulting from failure to implement a planned or a market approach include an estimated

4 The cost estimate for additional reserves is based on the average net revenue requirement of the clean energy supply conventional gas-fired contracts signed by OPA ($7,900 per MW-month) (OEB 2013a, p .17).

5 The new Napanee Generating Station gas-fired plant will receive at least $15,200 per MW of installed capacity each month, regardless of output (OPA 2012f).

additional $900 million to move gas-fired plants out of Oakville and Mississauga and $28 million to convert OPG's Thunder Bay Generating Station from coal to gas after spending $190 million on its construction (Legislative Assembly of Ontario 2013).

Furthermore, the ministerial-directed conversion of the Atikokan coal-fired plant into a biomass-fired operation will cost $170 million. The plant will have a levelized cost of more than twice that of a combined cycle natural gas plant (see Appendix for calculation and OPG N.D.).

Politicization of Power Sector Investment Decisions

Power sector investments are capital-intensive and long-lived. A lack of constancy in power sector policies reduces the willingness of private investors to participate. Government intervention becomes self-perpetuating, as the province replaces (directly through OPG or indirectly through OPA) private risk-taking capital. Without proper safeguards, this transfer of risk from private investors to ratepayers and/or taxpayers can result in inefficient capital allocations, as governments stray from commercial objectives and apply artificially low hurdle rates to specific projects, if they apply a hurdle rate at all.

Furthermore, the electricity sector can become a convenient instrument for policy implementation, regardless of the corresponding economic merits or lack thereof. Given the mismatch between short-run political horizons (four to six years) and long-run, least-cost planning (10 to 20 years), it is critical to have appropriate safeguards in place to prevent election-driven policy volatility.

A properly functioning power sector policy framework begins with government setting broad objectives, which are then implemented through independent institutions and market mechanisms. It does not involve, as has too often been the case in Ontario, the government issuing directives for specific actions without thoughtful analysis and transparent deliberation. The most appropriate policy objective for the power sector is to meet the reliability expectations of the average customer at long run, least cost within prevailing environmental regulations.

Unless institutions are truly autonomous, many politicians are unable to resist the temptation to circumvent electricity-sector policymaking processes. Autonomy from government does not mean being exempt from government oversight, but it does mean that qualified executives and boards are allowed to organize their activities consistent with clear mandates and are free from unscheduled interventions by policymakers.

The first way to establish electricity market independence is to ensure the independence of board members and revenue streams. Board independence is a necessary but not sufficient precondition for institutional independence – the entities need also to have dedicated funding streams that are not subject to the whims of the legislature.[6] Neighboring US states protect the independence of key institutions with defined terms of office for board members and require that the board not be solely in the hands of one political party. Board member terms need to be staggered, and removal only based on a limited number of conditions such as criminal activity or mental instability (Table 1).

6 The OEB is funded by fees, assessments and administrative penalties it collects from regulated entities (OEB 2010, Article 13.3). For its part, the OPA's operating budget is funded by fees on electricity consumers ($0.551/MWh) and registration fees on OPA procurements (OPA 2013, page 10).

Table 1: Comparison of Board Selection Criteria in Ontario, New York, and Michigan

Body	Ontario Energy Board	Ontario Power Authority	Ontario Energy Financial Corporation	New York State Public Service Commission	Michigan Public Service Commission
Number of members	At least five (currently 6 full time, 4 part time)	11	At least 2 and not more than 12 directors (currently 8)	5	3
Appointed by	The Lieutenant Governor in Council. In practice, nominated by the Minister of Energy	Minister of Energy	Appointed by the Lieutenant Governor in Council and is accountable to the Minister of Finance	Governor	Governor
Confirmation required?	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Confirmation by Senate	Consent of the Senate
Nomination committee?	No	Self nomination if there is vacancy	No	Yes, governor cannot reject nomination list twice	No
Limitation on political parties?	No	No	No	No more than 3 members may represent the same political party	No more than two Commissioners may represent the same political party
Explicit qualitifaction requirement?	No	No	No, the current Board is largely comprised of public servants employed by the Crown	Yes, education and training and 3 or more years of experience in fields of economics, engineering, law, accounting, etc.	None
Term	First term shall not exceed 2 years, may be reappointed for one or more terms of office, each of which does not exceed 5 years	Hold office at pleasure for initial term not exceeding two years and may be reappointed for successive terms not exceeding five years each	Hold office at pleasure for a term not exceeding 3 years and may be reappointed for successive terms not exceeding 3 years each	6 years	Staggered 6 years term

Sources: State and provincial laws and regulations.

The second independence measure is government divestiture of its remaining electricity assets owned by OPG, such as an "inclusive privatization" involving pension funds, unions and community or social organizations in the shareholding structure.[7] The outcome is that the resulting entities focus on achieving commercial objectives within a broad policy framework applicable to all such companies.

Challenges with the Global Adjustment

The GA obscures the costs of market interventions and interferes with economically efficient decision making in several ways. It distorts price signals: customers see the GA assessment only after they have made their consumption decisions. The GA, therefore, directly undercuts consumer efforts to save money by altering their demand levels and patterns because any resulting declines in wholesale revenue are offset by reciprocal increases in the GA.

The GA also makes consumer bills less comprehensible, potentially undermining consumer acceptance of power sector policies. Programs for large users serve to further mute price signals to these customer classes and blunt the incentive for companies to seek contracts on their own. The GA co-mingles costs to achieve environmental objectives with those related to reliability goals. Finally, this lack of transparency can lead to policymakers hiding the consequences of poor decisions.

By working to eliminate the GA, Ontario could improve the fidelity of the price signal to final consumers. Among other benefits, this would reduce the yo-yo effect of suppressing wholesale prices on one hand, and thereby potentially increasing demand, and on the other hand spending on programs that encourage consumers to alter their usage patterns. Such consumer programs, also known as demand-side management, work best when customers' power charges are comprehensive and transparent.

Why a Capacity Market is Appropriate for Ontario

One way to reintroduce market discipline to the Ontario electricity sector would be to introduce a capacity market. North American wholesale electricity markets have evolved in one of two ways: energy-only markets, such as Alberta and the Electric Reliability Council of Texas, or capacity markets. In an energy-only market, participant revenues are determined either by spot market activity or by bilateral contract positions.

For energy-only markets to work properly, policymakers must allow them to reach peak prices, which reflect a scarcity value, to provide price signals to new entrants. Competitive wholesale markets with price caps, particularly when those price caps are significantly below the level of economic losses caused by an outage, may fail to provide such signals. When allowed to operate smoothly, energy-only markets can be the most economically efficient design for competitive wholesale electricity markets. However, an energy-only market in Ontario might be greeted with skepticism by investors, given the province's history of suppressing price signals.

Capacity markets provide an additional revenue stream from "capacity" payments – a payment that a plant receives for available supply even if it is not dispatched, provided that it is able to produce electricity, if required. US capacity markets (Table 2)

7 The shareholder arrangements for Bruce Power (a partnership among Cameco Corp., TransCanada Corp., the Power Workers' Union, the Society of Energy Professionals and indirectly the Ontario Municipal Employees Retirement System) present a model for incorporating private capital into OPG or its divisions.

Table 2: Selected ISO Capacity Market Designs

ISO	Capacity market design summary
California	• Spot capacity market, serves 1 state, since 2004* • No centralized capacity market currently in place; system-wide Resource Adequacy Requirement ("RAR") and local RAR satisfied by utilities/LSEs on annual and monthly basis through bilateral trading of capacity • LSEs issue long-term requests for proposals and their longer-term procurement plans
New England	• Forward capacity market, serves 6 states, since 2006 • Use of 3-year forwards via Forward Capacity Auction with annual reconfiguration auctions • Local requirement for import constrained areas; with commitment period start, LSEs and generators can also participate in seasonal and monthly reconfiguration auctions
Midcontinent	• Voluntary capacity market, serves 11 states, since 2009 • LSE are required to buy from supply resources (which participate) in order to comply with the resource adequacy requirement in their zones
New York	• Spot capacity market, serves 1 state, since 1999 • Monthly Installed Capacity Spot Market Auction • LSEs with unmet resource adequacy obliged to purchase capacity and offer excess capacity
PJM (Northeast US)	• Forward capacity market, serves 13 states and District of Columbia, since 2007 • 3-year ahead Forward Capacity Market that relies on a downward sloping demand curve • LSEs can use self-supply and bilateral contracts and residual capacity procured in competitive auction

Note: *CAISO System RAR instituted in 2004 and Local RAR in 2006.

Sources: various ISOs.

exist in California (CA-ISO), New England (ISO-NE), the Midwest (MISO), New York (NYISO) and PJM, which serves all or part of 13 states between Illinois and New Jersey (PJM). Capacity markets provide an additional means of signaling when the market needs new generation capacity. One of the key motivations for implementing capacity markets has been to replace the so-called "missing-money" problem that arises when governments and regulators seek to suppress peak prices, for example through price caps.

Capacity markets have faced several challenges. In their initial designs, capacity prices were not known more than a year in advance, meaning developers needed to forecast future prices and convince their financers to consider the associated revenue stream in determining the asset's debt-carrying capability. As a result, some capacity markets have been redesigned to allow a three-year forward timeframe.

Capacity markets also tend to be binary – during periods of surplus, capacity is worthless. When scarcity conditions arise, the capacity price increases to a capped price that the system operator sets, usually at the amortized cost of a new simple cycle gas turbine. This amortized cost serves as a proxy for an economic means of meeting peak load. System operators have attempted to address the binary nature of capacity markets through the creation of floor prices and adjusting minimum prices based on reserve margins and bids.

Why the Status Quo Is Not Sustainable

The current Ontario power sector structure is not sustainable. Repeated use of ministerial directives increases uncertainty about policy direction and durability. The FIT program exacerbates imbalances in supply composition and increases costs. Requiring a provincially owned generator to pursue investments for other than purely commercial reasons creates additional cost challenges. Price suppression and distortion through the GA and other means produces inefficient consumption decisions.

As Ontario power costs diverge from those in neighbouring states and provinces, economic activity may suffer. Eventually, the province's credit rating may be at risk if rising prices and falling demand lead to stranded assets coupled with implicitly provincially backed entities.[8] However, Ontario can address all these issues if it focuses on improving price signals, codifying autonomy for provincial electricity institutions and deploying long-run, least-cost approaches to meeting stated policy objectives. Recent initiatives suggest the government is seeking to address these challenges in an economically rational fashion. However, broader reforms are still necessary.

Part 2: Creating a Meaningful Long-Term Price Signal for Power in Ontario

The Ontario power sector already contains the necessary building blocks to create a stable long-term investment climate. Instead of replacing (or merging) existing institutions, policymakers should refocus them on long-run economic efficiency, including providing effective and transparent price signals. Obscuring price signals ultimately reduces social welfare by leading to a misallocation of resources.

Providing Appropriate Price Signals and Reallocating Risk

In the late 1990s, the province began to create a more dynamic and innovative power sector than existed under Ontario Hydro. However, while more power generation participants have entered the market as a result, the number of potential counterparties has remained narrow. The OPA has crowded out private long-term electricity buyers: generating companies have little incentive to seek alternative purchasers and electricity buyers cannot match the credit quality and duration of OPA contracts. These contracts shift operational risks to the developer's shareholders (if the plant fails to operate, the developer does not get paid), along with the risk of cost overruns. Ratepayers, however, bear the risk that OPA will over-contract on their behalf.

Risk allocation becomes awkward when the government directs the OPA to contract with OPG, as such contracts simply shift risk between ratepayers and taxpayers. Failing to subject OPG to the same discipline that private developers face – the need to bid for and win contracts and to stay within expected budgets – means that ratepayers, rather than shareholders, end up paying for cost overruns. Even if OPG did bear the burden of cost overruns, taxpayers would ultimately pay the cost through reduced dividends.

8 While OPG and OPA may be ostensibly arms-length from the provincial government, the spillover effects on the province's credit from allowing either to default makes it unlikely that rating agencies would ignore their liabilities in assessing the province's overall creditworthiness.

By re-orienting the Ontario power sector away from OPA as a principal buyer, the province can reallocate risks and make price signals more transparent, which would improve investment and consumption decisions.[9] Diversifying procurement responsibilities would reduce risks of oversupply. If private companies were on the power purchasing side, their shareholders would face lower profits if the companies over-contract, whereas entities like OPA face limited consequences in similar situations. Indeed, relying solely on private capital for future investment will result in building least-cost generating facilities to meet power supply needs consistent with environmental laws.

Stages of Market Evolution

The province should take six steps to transition the Ontario power market to a durable set of arrangements that would produce long-run, least cost power supplies for consumers.

1. *Strengthen the autonomy of power sector institutions.*
2. *Address the role of nuclear.*
3. *Create load serving entities* required to participate in a resource adequacy market (RAM).
4. *Establish a resource adequacy market.*
5. *Reallocate capacity* (total plant output potential, expressed in MW) and energy (production, which occurs when capacity is called upon, expressed in MWh) from existing OPA contracts to load serving entities (LSEs), with all subsequent contracting driven by LSE perceptions of need relative to their resource adequacy market responsibilities.
6. *Provide customers with default supply options,* which pass through prices from resource adequacy markets (RAMs) and spot markets, with those wishing to hedge able to do so using competitive offerings from LSEs.

Power Sector Autonomy

The first step in setting a proper foundation for power market evolution is to enshrine the independence of key market institutions and clarify their mandates. Once the long-term policy direction for the power sector has been defined, policymakers then need to put distance between themselves and the implementing institutions. In Ontario, the government can assure some measure of independence by insulating OEB, IESO and OPA board members from removal for any reason other than expiration of term, mental incompetence or moral turpitude, and by providing dedicated funding mechanisms for those institutions.

The government should abandon efforts, currently on hold, to merge the OPA and IESO. Due to the difference in functions between the two agencies, savings from the combination are likely illusionary, and the potential for conflict of interest is rife. While the few areas where functions are duplicated should be allocated to one or the other, maintaining the two as separate entities is critical to the integrity of the Ontario power market. Mixing the functions of market and transmission operator with that of contract administration may raise the suspicions of market participants that the combined entity will operate in a fashion that reduces OPA-related costs at the expense of other market participants while undermining the fidelity of the

9 Those who laud the simplicity of an OPA contracting regime should consider the systemic imperative for central procurement entities to over-contract. The consequences for undersupply are felt immediately, while costs of oversupply only become apparent over a long period of time, and possibly after the decision-maker is no longer in the job. The simplicity will prove costly to ratepayers unless the procurement entity and its regulator are arms-length from politicians, and the long-term procurement plans (including the associated target reserve margins) are subjected to full and proper regulatory review.

market price signal. This may drive participants from the market, increasing future investment costs and reducing the diversity of actors.[10]

The government should expand the IESO's mandate to include administration of a long-term capacity market. On the other hand, OPA's mandate should narrow. Originally intended as a transitional agency,[11] OPA was designed to address a looming supply shortfall by providing stability to investors while the Ontario power market steadied. OPA successfully accomplished this.

Through subsequent procurements and FIT, OPA also catalyzed the creation of a local private-sector renewable energy industry. Now that the government has achieved these goals, and once contracts for nuclear refurbishment contracts are in place, it should direct the OPA to cease further contracting, focus on contract renegotiations to reduce the GA and, ultimately, become a pure contracts administrator. The OPA should wind down its conservation programs consistent with a plan to enhance market price signals for efficient demand-side management, while IESO designs demand-response programs consistent with its market operations. The OEB would periodically review the OPA's budget, its progress in reducing the GA and plans for shrinking.

Assessing the Role for Nuclear

Future Ontario power sector investors need to know the government strategy for nuclear energy. Investors will be hesitant to make market-based commitments to new generation investments until the government establishes the future size of Ontario's nuclear fleet. Most new nuclear projects will not be cost competitive with combined cycle gas turbines (CCGT) unless natural gas prices increase significantly and carbon is heavily taxed (Figure 6). While some refurbishment projects may be competitive with new baseload gas-fired plants when environmental externalities are considered, new nuclear is not likely to be cost competitive. Meanwhile, existing nuclear power stations should not be abandoned lightly but, at the same time, nuclear should not be preserved at any cost.

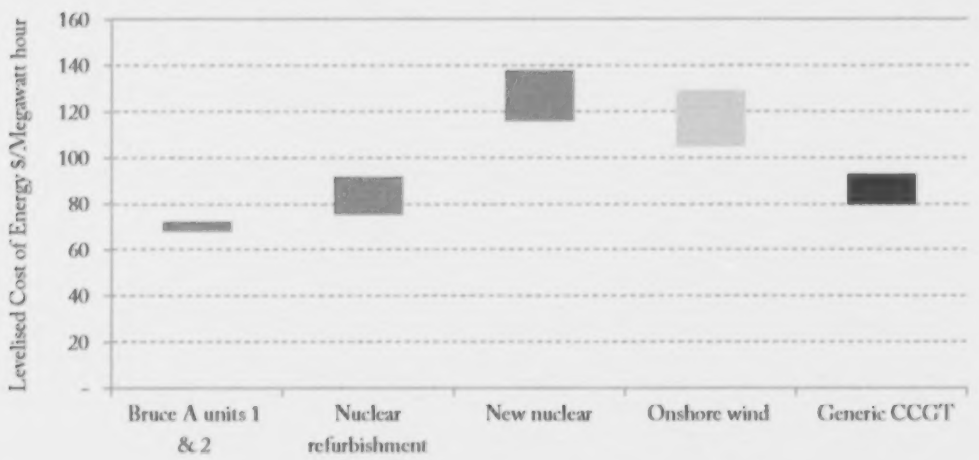
The OPA should hold one final nuclear procurement round based on an announced threshold price and an assessment of the timing of need for baseload resources. The threshold price should be based on the levelized cost of a new CCGT, incorporating an appropriate present value of the cost for carbon and natural gas.[12] In the event that the procurement failed to result in nuclear generators matching the cost of natural gas generators, site owners would be free to redevelop the sites of the proposed nuclear plants as they saw fit (including conversion to gas), but would do so solely on the basis of revenues from spot markets, bilateral contracts and the resource adequacy market described below.

10 More appropriate candidates for merger would be the OPA and OEFC, given that both administer long-term contracts, though OEFC's role will gradually diminish as contracts expire.

11 As Wyman (2008) notes: "Former OPA CEO Jan Carr suggests that the authority should be a "transitional agency" and will at some point "do itself out of a job." Reflecting this view, the OPA's 2007 business plan suggests that, "Over time, as the market develops sufficient ability to ensure timely investment in supply resources, the need for OPA procurement activities will decline."

12 Bid documents should note that no bids above the threshold price would be accepted. While the Ontario market should evolve toward technology-neutral generation investment signals, this final procurement can test the value of the existing nuclear endowment against a natural gas default option. Alternatively, the final procurement round could define the product consistent with what refurbished nuclear plants would be able to supply (baseload power for 20 years commencing approximately five years from the auction date), but allow all technologies to bid.

Figure 6: LCOE* Comparison between Nuclear Refurbishments, New Nuclear, Onshore Wind and Generic CCGT



Notes: * Levelized Cost of Energy.
LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. CCGT LCOE low estimate based on 85% capacity factor, with natural gas prices based on net present value of 20-year forecast prices, a $20/ton carbon price, and EIA (2012) capital cost assumptions. CCGT LCOE high-end estimate based on 70% capacity factor, $7.5/MMBtu gas price, a $20/ton carbon price, and costs based on Ontario-specific cost average. Refurbishment cost of Bruce based on actual announced cost and contract price with OPA. Other nuclear refurbishment costs based on average for Darlington, Gentilly, and Point Lapreau. LCOE of new nuclear based on EIA (2012) assumptions and on average costs of Olkiluoto (Finland) and Flamanville (France) European Pressurized Reactor plants currently under construction. Onshore wind LCOE based on FIT 2.0 price schedule and EIA (2012) assumptions. Weighted average cost of capital ("WACC") for all projects assumed to be 8.88%. See also Appendix A.

Identifying Load Serving Entities

A properly functioning energy market has an appropriate number of sellers and, equally important, buyers. An important step in creating a more robust set of such counterparties is to increase the number of entities with a direct responsibility for purchasing electricity. Such "load serving entities" (LSEs) would be responsible for providing customers with the commodity portion of their load, as distinct from its transportation. An LSE can be a competitive retailer or a utility, but its defining characteristic is that it faces consequences should it fail to provide the energy and capacity contracted by an end-user.[13] LSEs are

13 For the purposes of this *Commentary*, customers directly connected to the transmission system would also be considered to be LSEs, subject to the same rights and obligations as the LSEs created to serve residential customers. Directly connected customers, as well as existing competitive retailers, would face capacity obligations, but would be included in the pro-rata allocation of OPA-contracted capacity described here.

the predominant form of organization to meet load obligations in competitive electricity markets.

Existing electricity local distribution company (LDC) service territories in Ontario are the logical starting point for creation of LSEs. However, Ontario LDCs are regulated businesses of varying size and capabilities that are already facing significant pressure as they seek to upgrade their physical plants and comply with the province's incentive-rate system. This suggests that creation of LSEs within LDCs could prove to be a distraction and may not be effective. As an alternative, the OPA could establish four or five new LSEs for sale by auction to the private sector, with a set of contiguous LDC service territories as boundaries.[14]

The new LSEs would be responsible for procuring energy and capacity on behalf of customers within their initial service territories. However, end customers – business and residential – would be able to choose third-party retailers as their LSEs, and the new LSEs would be eligible to compete in the territories of the other LSEs. The LSEs would be auctioned to experienced commercial companies, accompanied by a pro rata allocation of existing OPA capacity volumes. This pro rata allocation would be further divided proportionally among the LSEs' regulated customers (who have yet to choose a competitive supplier) and competitive customers.[15]

Creating a Resource Adequacy Market

To facilitate the move from Ontario's semi-planned, principal-buyer-based market, Ontario should establish a long-term resource adequacy market (RAM), a form of capacity market. In contrast to energy-only markets, the RAM would require LSEs to procure sufficient capacity (usually denominated in $/kW over a unit of time, such as a month) to meet a target reserve margin. Thus, an LSE would, in addition to procuring sufficient energy to meet its customer's needs, be required to calculate each customer's peak load and procure sufficient capacity to meet that peak load plus a reserve margin. For example, if the customer peak load is 100 MW and the target reserve margin is 15 percent, the required amount of capacity the LSE must purchase is 115 MW (Table 3).

The RAM would be a form of laddered capacity market, with purchase requirements decreasing for years further into the future. Such capacity markets are an administrative method of addressing a perceived market failure in which the contract length customers are willing to enter into for hedging purposes is too short to provide sufficient certainty for financing. In addition to providing greater long-term price transparency, the laddered capacity market would provide some elasticity to capacity pricing in future years.

Under a RAM regime, the IESO would set target internal reserve margins and administer

14 LSE territories would not map directly to the outline of all existing LDCs since some, such as Hydro One, own non-contiguous territories. Existing LDCs – or a group of LDCs – would be allowed to bid on LSE franchises through their unregulated subsidiaries, subject to current affiliate-relations codes designed to prevent the use of utility brands to create an unfair advantage in the retail market. Bidders for LSEs would have the right to supply and the obligation to serve existing regulated customers; this relationship may be valuable as a hedge for new generation businesses and for building new retail platforms. Within the confines of existing privacy laws, bidders would have information on customer numbers prior to the auction, on levels of demand and on load shapes. Proceeds from the auction would be used to reduce the GA.

15 The default offering for regulated customers would be divided between an energy and capacity component; the existing GA would continue to be assessed by LDCs on wire charges to assure that it remained non-bypassable.

Table 3: Indicative Forward Capacity Purchasing Requirements for LSEs

	Years from present time						
	+1	+2	+3	+4	+5	+6	+7
	(*Percent*)						
Capacity contracting requirement as percentage of current peak load in the specified future year	115	115	115	115	115	115	115
Share of requirement to be procured in present year	100	100	100	90	80	70	60
Effective capacity contracting requirement in present year	115	115	115	104	92	81	69

Source: Hypothetical example.

forward capacity markets. To provide a meaningful long-term investment signal,[16] LSEs would be required to demonstrate sufficient capacity to meet their current load plus required reserves for three years into the future, based on IESO projections. In addition, the LSEs would be required to contract for a declining proportion of current load plus reserves for each year, four to seven years into the future (see a representative example in Table 3). LSEs failing to meet their requirements would face a penalty equal to the monthly amortized cost of a new simple cycle gas turbine.

Capacity payments are substitutes for what would otherwise be higher peak prices. An effective capacity market may allow for reserve margin targets to be met with less need for super-peak pricing to signal that entry is necessary. New entrants may apply a lower capital cost to markets with multiple durable revenue streams, reducing long-run marginal costs. Furthermore, the cost of reliability itself becomes more explicit, allowing for more informed discussion of the trade-offs embodied in selecting a particular target reserve margin.

16 The seven-year laddered purchase requirement is intended to provide a long-term price signal that facilitates longer-term debt financing for developers, while not unduly burdening retailers. IESO will need to pay careful attention to the design of prudential requirements on LSEs and others trading in the RAM, so that credit requirements do not serve as undue barriers to entry in the retail market while protecting against the consequences of default.

Initially, and quarterly thereafter, the IESO would launch an auction for capacity for each of the years in the full seven-year forward period. Existing generators and new entrants would sell capacity not currently under OPA contract into the auction, and LSEs would purchase their requirements through the auction. LSEs would be allowed to procure capacity through bilateral contracts, but would need to register the contract with the IESO for compliance purposes. Other details, such as floor prices, would be subject to market design deliberations.[17]

Intermittent resources would be eligible for capacity based on resource-specific average seasonal capacity factors calculated by the IESO based on contribution to peak load. Generators with the most intermittent production should be disproportionately discounted in capacity markets, with the most reliable generating sources getting a higher capacity credit in capacity auctions.

Because of current ample supply in Ontario, it may be several years before a RAM would signal significant investment needs. However, the IESO should be attentive to synchronization of market rules with neighbouring markets to allow capacity export (or import). Because capacity cannot be sold in two markets simultaneously, subject to the amount of firm transmission available, capacity prices in neighbouring markets can help to provide an implicit floor for Ontario prices during years when the IESO-administered floor price related to low projected reserve margins is not in place.

Capacity Reallocation

OPA contracts represent the majority of provincial capacity. Dealing with existing contracts would require that they be transferred to the LSEs. However, a transfer of individual contracts could be administratively complex.[18] A more straightforward approach would be to allocate all of OPA's capacity to the LSEs, for a nominal dollar, on a pro rata basis using back-to-back contracts.[19] This means that over time, the contract capacity would taper off, after rising in early years for plants that have been contracted for but are not yet online.[20]

All LSEs registered by a cut-off date would be eligible for the capacity allocation based on their demonstrated existing peak load commitments. This vesting-style approach provides substance to newly formed LSEs by clarifying available supply.[21]

17 One of the biggest changes in capacity markets has been the increased ability of demand-response aggregators (entities that assemble commitments and capabilities to reduce load from smaller customers into blocks large enough to be dispatched) to participate. While demand response and physical generation are not equivalent, demand-response aggregators have proven to be highly flexible and have aided in maintaining reliability during tight supply situations. These aggregators would be eligible to participate in capacity auctions, subject to the same deliverability standards as conventional generation.

18 Rather than assigning existing OPA contracts, a better option would be for OPA to resell or assign the associated capacity to LSEs using new contracts. Existing OPA counterparties would see no change to their contractual relationship with OPA. Capacity allocation is a one-time exercise – once completed, it would not occur again, minimizing the possibility of investor uncertainty.

19 Because customers have already paid for existing capacity through the GA, and will continue to do so, it is not necessary for OPA to charge the LSEs for the capacity. Because the LSEs would be contracting for their net needs through the RAM, RAM pricing would reflect the non-energy costs of incremental capacity.

20 The outlook of future contracted capacity includes contracts that have been approved and are in process of being built; the moratorium would apply only to new incremental contracts.

21 LSEs would be allowed to sell surplus allocated capacity in neighbouring markets. Presumably, bidders for LSEs would incorporate this potential benefit into their LSE valuations, meaning customers would ultimately benefit since LSE auction proceeds would revert to customers through a GA reduction.

Default Supply Options

In a properly functioning energy market, each LSE would be required to offer its customers a default alternative of spot price plus RAM pass-through, similar to current prices. Customers on time-of-use (TOU) pricing would remain on the OEB price schedule if they lacked real-time meters (see Box 2). But they would be free to switch based on LSE competitive offerings, which would likely include long-term fixed prices for energy and RAM capacity.[22] To assure appropriate customer attribution of capacity transferred from the OPA, LSEs would be required to allocate this capacity monthly on a pro rata basis between default and contracted capacity.[23]

Why this Approach Is the Best Alternative for Ontario

Continuation of centralized contracting runs the risk that the government will use the power sector to meet the needs of narrow sets of constituencies at the expense of ratepayers as a whole. Even if current procurement arrangements can be sufficiently depoliticized, central planners may not be able to resist the temptation to stray from technologically neutral approaches.

By contrast, immediate transition to an energy-only market is also unfeasible. Investors would doubt that the government will allow prices to rise to levels that would make investment attractive.

The proposed RAM incorporates the best features of neighbouring markets, facilitating potential integration. At the same time, it creates a role for market-driven demand response. Customers would not pay twice for existing capacity: capacity under existing contracts will have already been allocated to LSEs, effectively making the RAM a residual capacity market. If accompanied by economy-wide efforts to price negative externalities from emissions and effluents, the arrangements would ultimately facilitate market-driven private-sector investments in the Ontario power sector consistent with the province's environmental goals.

Part 3: Related Issues

The evolution of wholesale electricity markets does not occur in a vacuum. This is particularly true in Ontario, where the current fuel mix is a legacy of prior government policies, resulting in a cascade of potential nuclear retirements through the coming decade. Choices for electricity market policy are shaped by, and in turn impact, pre-existing contracts and commitments along with climate change policies. Below, I discuss a range of issues that need to be considered in parallel with stabilizing the Ontario electricity market, along with potential complementary policies.

Evolution of OPG

For the RAM to work properly, it needs to

22 In order to offer fixed prices on RAM capacity, LSEs would need to be active participants in the RAM. Because of the requirement to contract for RAM seven years forward, LSEs would likely offer consumers forward terms of up to seven years; restrictions on switching after contracting but before the end of the contract term would be based on the LSE's commercial terms and conditions.

23 The RAM price pass-through for default customers would be a weighted average of the near-zero cost of the OPA-related component and the market-procured RAM capacity. Access to the OPA-related capacity volumes for contracted quantities would allow LSEs to craft competitive offerings while preventing creation of perverse incentives for default customers to avoid switching.

Box 2: Current Retail Supply Arrangements in Ontario

Currently, residential and small business consumers who buy their electricity directly from their local utility (instead of from retailers) pay either a tiered or time-of-use (TOU) rate according to the Regulated Price Plan (RPP), depending on whether they have smart meters.

RPP prices are set by the OEB and reviewed twice per year. To calculate RPP prices, the OEB forecasts the cost to supply electricity to RPP consumers for the next 12 months, taking into account factors such as forecast prices for coal and natural gas, supply-fuel mix, contracts with generators and demand forecast.

While all Ontario electricity consumers are required to pay their share of the GA, a forecast of the GA is also included in the RPP prices and, therefore, is not shown separately on the bill.

Effective May 1, 2013, the peak TOU price increased from 11.8 cents/kWh to 12.4 cents/kWh, and the off-peak price increased by 0.4 cents to 6.7 cent/kWh. For tiered prices, the first tier (up to 600 kWh per month for households) price will be 7.8 cents/kWh (0.4-cent increase from previous RPP). Above the tier threshold, the price will increase from 8.7 to 9.1 cents/kWh.

As of April 5, 2013, more than 80 percent of RPP-eligible consumers were on TOU billing.

Source: Ontario Energy Board (2013b).

incorporate OPG assets, and future OPG investments need to be driven by market forces.[24] While privatization of some or all of OPG would be beneficial to place it beyond the reach of ministerial directives, there are steps the government should consider other than privatization to improve the functioning of the Ontario wholesale power market.

OPA should develop contracts with OPG on a plant-by-plant basis for OPG prescribed assets, excluding contracts for new nuclear or nuclear refurbishment.[25] This would allow policymakers and company management greater flexibility in asset configuration should the government one day privatize OPG. These contracts would need to be sufficiently long to maintain OPG credit quality, but thereafter, provided OPG or its successor companies lacked market power, no further contracts other than those obtained commercially would be required.[26] OPG's non-prescribed assets would remain merchant, able to sell into both the energy market and the RAM, or enter into bilateral contracts.

Once the contracts commence, OPG would

24 OPG-prescribed assets include all nuclear facilities (Darlington and Pickering A and B) and most of its baseload hydroelectric facilities (Sir Adam Beck 1 and 2, DeCew Falls 1 and 2, and R.H. Saunders). For electricity generated by its prescribed facilities, OPG receives a regulated price determined by the OEB (OPG 2011).

25 For hydro plants on a single river system, a bundled contract could be considered.

26 Recent announcements that OPG will be allowed to bid for large-scale renewables contracts raise several potential concerns, however. While the shutdown of coal capacity has reduced OPG's overall market share, it remains dominant. Private-sector players competing against OPG will question whether OPG applies a commercially reasonable cost of capital to its projects and whether OPG has unfair access to sites, particularly those with favourable grid access. OPG has little experience with non-hydro renewable technologies, and investors may also question OPA's ability to negotiate as aggressively with OPG as it does with private entities if key contract milestones are missed.

no longer need to be rate regulated by OEB, lessening the regulatory burden significantly for all stakeholders. Moving OPG assets from regulation to contracts puts all market participants on a more level playing field. Furthermore, it allows the capacity from OPG prescribed assets to be allocated among LSEs as part of the process described above.[27] Finally, if it proves politically challenging to sell OPG plants outright, dispatch rights associated with the contracts can be auctioned to other market participants, addressing market power concerns and deepening the electricity market.[28]

Optimization of Existing Contracts

Honouring existing contracts is an essential component of creating a favourable investment climate. However, the OPA should examine whether existing contractual provisions make sense in a reformed market. That means the OPA should seek negotiated, mutually beneficial contract amendments with existing contract holders. The recent Samsung renegotiation provides a sensible template for modifying existing contracts. Uncompelled contract renegotiations are a normal feature of every-day commercial relationships. There are many possible contractual re-arrangements possible, such as a lump-sum payment in return for contract terminations or lengthening contract terms in exchange for a decrease in prices.

OPA could issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments associated with the plant. OPA should be able to utilize securitization techniques to arbitrage differences in cost of capital between it and its counterparties. Counterparties would receive a lump-sum payment to exit their contracts; their facilities would then become merchant plants, increasing the relevance of wholesale spot markets and releasing capacity to be contracted with third parties. OPA would issue long-term debt to make the lump sum payments, with the debt backed by future GA payments. Provided that payments on the debt are lower than the payments that OPA would otherwise have made on the terminated contracts, the GA would fall.

Cost-effectively Fulfilling Environmental Objectives

Power from fossil-fuels, even natural gas, produces climate change-causing carbon dioxide (CO_2) emissions. One of the lowest-cost ways to reduce CO_2 emissions is a cap-and-trade mechanism. A practical way for Ontario to implement cap-and-trade would be to join the cross-border Western Climate Initiative (WCI,[29] a system whereby designated polluters must obtain CO_2 credits from

27 While this capacity could theoretically still be allocated while remaining under regulation, mechanisms would need to be devised to ensure that all upgrades of regulated assets are financed on a market basis. Moving regulated assets to a contract basis would create greater investor confidence that OPG is not being subsidized by ratepayers.

28 A public entity like the Alberta Balancing Pool need not be created for this exercise; numerous examples of private-sector contracts transferring dispatch rights, such as tolling agreements, exist without the need for an intermediary. The Balancing Pool arose partially to serve as the counterparty for unsold dispatch rights, a problem that can be avoided through appropriate auction design.

29 The December 2009 Climate Change Action Plan set targets for reducing Ontario's greenhouse gas emissions ("GHG emissions"): 6% below 1990s levels by 2014, 15% by 2020 and 80% by 2050 and foresees working with WCI to design a cap-and-trade program. WCI is a collaboration of four Canadian jurisdictions (British Columbia, Manitoba, Quebec and Ontario) and California to develop infrastructure and administrative tools to support a regional GHG trading framework (Ontario Ministry of the Environment 2009, N.D.).

an emissions trading market. Under a WCI cap-and-trade scheme, Ontario could set the maximum amount of emissions credits it would allow in the market, reducing the amount over time in order to reduce emissions, and auction credits to the highest bidder. Because Ontario would be joining Quebec and California in an expanding continental emissions credit market, Ontario participants would have the benefits of a liquid market. The province would gain additional revenues from the sale of emissions credits consistent with the provincially set cap on CO_2 emissions.

Coupled with a phase-out of the FIT and renewables-specific procurements, joining WCI could ultimately be a more efficient way for Ontario to achieve environmental objectives than subsidizing wind power through a FIT program. If the price of delivered natural gas rose to $10 per MMBtu, a carbon dioxide emissions reduction credit price of $18 per ton would be needed for a wind generator to achieve the same revenues as it would under the FIT (Figure 7). Even if emission credit prices were to exceed $110 per ton of CO_2 and natural gas remains at the current price of about $4 per MMBtu, natural gas power plants would still be a lower-cost electricity source than the current wind FIT program.

Ontario could also reduce the cost impacts on its electricity consumers if it were to adopt a so-called "cap-and-dividend" approach, with the proceeds of emissions credit auctions applied toward reducing the GA.[30] Furthermore, Ontario could design floor and ceiling mechanisms, including "safety valves" involving greater use of emissions offsets, to manage emissions credit-price volatility.[31]

Part 4: Next Steps for the Province

"Press Pause"

To assure a sound foundation for future power sector policies, the provincial government should put all new contracting initiatives on hold and announce a moratorium on decisions affecting the wholesale generation market until a comprehensive and transparent policy review can be performed by a special review panel. Such a review should be time limited and include a consultative process. Terms of reference should focus on how to create a durable structure for the Ontario power sector to provide reliable electricity supply at long-run, least cost. This review would provide an opportunity for the province and stakeholders to consider the optimal structure for the energy industry.

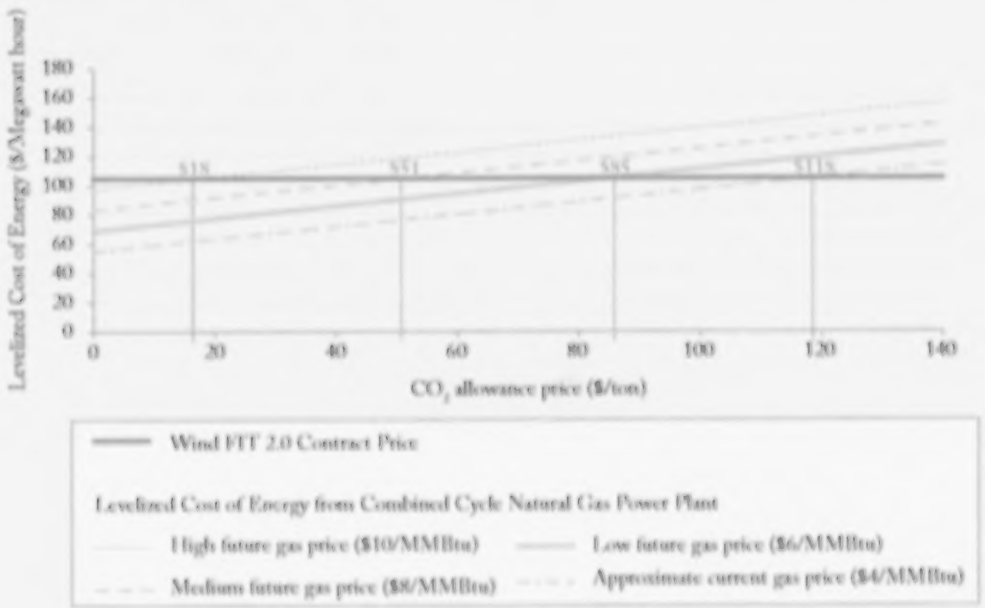
To inform the review, the OPA and IESO should perform a high-level, 10-year forward analysis of potential generation needs under various demand scenarios. Such an analysis should be technology and ownership neutral, but should highlight when and where on the supply curve (baseload, mid-merit or peaking) those needs are likely to arise.[32]

30 Change-of-law provisions in some OPA contracts may mean that some producers would pass through costs of emissions credits to consumers through the GA; a cap-and-dividend approach would offset the impact on consumers. A drawback of the cap-and-dividend method, however, is that it mutes the pricing of negative externalities for consumers.

31 In January 2013, the Ontario Ministry of the Environment published a discussion paper on ways to reduce greenhouse gas emissions, including applicability of a cap-and-trade scheme (Ontario Ministry of the Environment 2013, and Meloitzer 2013).

32 The consultation papers issued as part of the 2013 LTEP consultation process represent a good starting point for this analysis.

Figure 7: Implied Carbon Price Embedded within Wind FIT at Varying Natural Gas Prices



Note: Wind LCOE based on 30% capacity factor, 24-month construction period and $2,014/kW capital cost; gas prices range from a low of slightly above January 2013 levels to a level that is less than that which prevailed in 2008 prior to the world financial crisis.

Source: LEI calculations from OPA (2012g).

Indicative Timeline

If the government chooses to adopt a capacity market, reforms of market institutions could be gradually phased in before significant future capacity needs arise. An indicative timeline is outlined in Figure 8. Creating a capacity market will involve a number of steps, but is feasible within the lifetime of a single session of provincial parliament (see Box 3).

In the past, Ontario has made too many power sector changes simultaneously or issued policy changes too rapidly. Ideally, during the three-year capacity market implementation period, no other major changes in the power sector would be contemplated, at least on the generation side.

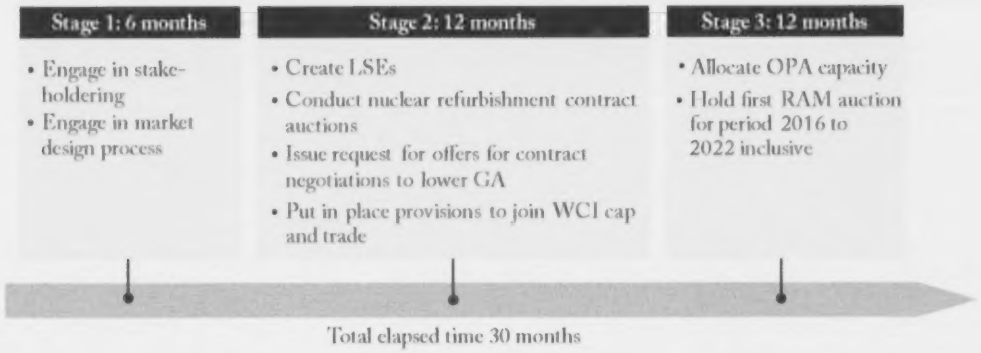
Assuring Political Viability

To avoid further cost increases and the risk of continued supply-demand mismatches, Ontario needs to have a comprehensive conversation about how to create a durable power market. Power market design evolutions are best implemented during a period of supply surplus, meaning that Ontario has a unique opportunity over the next few years to examine and implement changes that would put the power sector on a sound foundation

Box 3: The To-Do List for Ontario

1. Implement changes at relevant power market institutions to assure board members are independent, serve staggered defined terms and are subject to removal only for a limited number of reasons.
2. These institutions need dedicated funding streams protected from legislative whims.
3. Work to reduce, and even eliminate, the GA.
4. Re-orient the Ontario power sector away from the use of OPA as a principal buyer.
5. Enshrine the independence of key market institutions and clarify their mandates.
6. Maintain OPA and IESO as separate bodies.
7. Direct OPA to cease further contracting (including with expiring non-utility generators), focus on uncoerced mutually beneficial contract negotiations to reduce the GA and, ultimately, become a pure contracts administrator.
8. IESO should design demand-response programs consistent with its market operations.
9. The OEB should cease rate-regulating OPG prescribed assets, but periodically review OPA's budget, its progress in reducing the GA and plans for shrinking. OPA should develop contracts on a plant-by-plant basis for OPG-prescribed assets.
10. Explore the future role of nuclear. The OPA should hold a final procurement round, based on an announced maximum price consistent with a carbon-neutral CCGT and an assessment of the timing for baseload resource needs.
11. OPA should establish four or five new LSEs for sale by auction to the private sector, with their boundaries contiguous to LDC service territories. LDCs themselves would retain their current form and functions.
12. Form a new RAM and establish a laddered capacity market with purchase requirements decreasing with time.
13. Allocate all of OPA's capacity to the LSEs on a pro-rata basis, using back-to-back contracts. LSEs should then offer customers a default alternative of spot price plus RAM pass-through.
14. OPA should issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments.
15. Join an emerging Western Climate Initiative carbon dioxide emissions reduction credit market as a means to transition to cap-and-trade mechanisms.
16. Encourage demand-response aggregators and allow them to participate in capacity auctions.

Figure 8: Indicative Timeline for Consultative Process


Stage 1: 6 months
• Engage in stake-holdering
• Engage in market design process
Stage 2: 12 months
• Create LSEs
• Conduct nuclear refurbishment contract auctions
• Issue request for offers for contract negotiations to lower GA
• Put in place provisions to join WCI cap and trade
Stage 3: 12 months
• Allocate OPA capacity
• Hold first RAM auction for period 2016 to 2022 inclusive
Total elapsed time 30 months

Source: LEI.

for future investment. Doing so would benefit customers by returning the focus of power sector planning to long-run, least-cost principles, reducing the ability of policymakers to implement politically expedient measures that turn out to have hidden future costs.

In considering the proposed changes, the focus should be on decreasing long-term electricity costs while strengthening the Ontario economy. Consumers will welcome adjustments if they are convinced that costs will ultimately be contained. Rural Ontario would likely support the plan, provided it is clear that it does not entail any loss of local control. LDCs would not be forced to consolidate or become LSEs. Renewable energy projects would be market-based and not subsidized.

Three sources of opposition are possible: labour, environmental activists and privileged corporations.[33] However, each can likely be assuaged if the program is properly communicated and measures are taken to address specific concerns. While these proposed changes do not rely on privatization, unions should be encouraged to participate as owners should the government envision a sale of parts or all of OPG. Furthermore, given current demographics, protections for the existing workforce can be built into any sales agreements.

The changes I propose in no way undermine environmental protection and can be bundled easily with a meaningful climate change action plan. Indeed, implementing a cap-and-trade program as part of the WCI would demonstrate continued long-term commitment to the environment, as would focusing on economic demand-response programs.

33 Policymakers should not underestimate the possible extent of rent-seeking embedded in current Ontario arrangements, whether on the part of unions at provincially owned enterprises or clean-energy advocates in designing the Feed-in Tariff. The proposed framework would improve transparency and diminish the ability of parties to increase rents by bypassing the market in favour of government-sanctioned support from taxpayers or ratepayers.

Although corporate interests will no doubt complain about the lack of long-term contracts, many businesses recognize that the Ontario power sector as currently constructed is unsustainable. A credible plan for reducing electricity costs using market forces will ultimately win favor from investors.

The plans need not involve acknowledging any previous mistakes. A "mission accomplished" approach would focus on the fact that coal has been successfully eliminated, that the government has procured a significant amount of zero-emitting capacity and has created a supply surplus that enables the long-term reforms I propose.

Ontario's electricity institutions have matured to the point where their independence would be beneficial. Careful attention to messaging and repeated focus on how the plan reduces costs without harming labour or the environment will contribute to its success.

In short, common-sense solutions exist that will allow for a reduction in long-term Ontario power costs that will contribute to economic development. These solutions do not require the creation of new institutions, nor do they require abandoning key policy objectives such as environmental protection.

APPENDIX

Table A: Back Up to Levelized Cost of Energy Calculations

[2012 dollars]	CCGT	CCGT (high)	Biomass (Atikokan)	Onshore Wind (high)	Nuclear (Bruce A units 1 & 2) (high)	Nuclear Refurbishment (low)	New Nuclear (low)
Capital cost [$/kW]	1,016	1,230	8,500	2,535	3,200	3,338	5,339
Leverage	60%	60%	60%	60%	60%	60%	60%
Debt interest rate	8%	8%	8%	8%	8%	8%	8%
Tax rate	40%	40%	40%	40%	40%	40%	40%
After-tax required equity return	15%	15%	15%	15%	15%	15%	15%
Debt financing term	18	18	18	18	18	18	18
Equity contribution capital recovery term	20	20	20	20	20	20	20
Construction time (months)	36	36	48	24	72	60	72
Heat rate [Btu/kWh]	7,050	7,050	13,500		10,460	10,460	10,460
Nominal variable O&M [$/MWh]	3.6	3.6	5.2		2.1	2.1	2.1
CO_2 content [lb/MMBtu]	120	120					
Carbon cost [$/ton]		20.0					
CO_2 adder [$/MWh]		8.5					
Nominal fixed O&M [$/kW/year]	15.0	15.0	104.6	29.2	92.3	92.3	92.3
Capacity factor	85%	70%	85%	30%	90%	90%	90%
Fuel price [$/MMBtu]	$6.9	$7.5			$0.4	$0.4	$0.4
All-in fixed cost [$/kW-yr]	$144	$171	$1,215	$340	$536	$542	$833
Levelized non-fuel cost of new entry [$/MWh]	$23	$40	$168	$129	$70	$71	$108
Levelized Cost of Energy ("LCOE") of new entry[$/MWh]	**$71**	**$93**	**$168**	**$129**	**$75**	**$75**	**$112**

Table A: Continued

[2012 dollars]	CCGT	CCGT (high)	Biomass (Atikokan)	Onshore Wind (high)	Nuclear (Bruce A units 1 & 2) (high)	Nuclear Refurbishment (low)	New Nuclear (low)
Carrying charge until commissioning [$/kW]	$146	$177	$1,632	$243	$922	$801	$1,538
Amortized carrying charge over debt term [$/kW/year]	$12	$15	$137	$20	$78	$67	$129
Debt-financed portion [$/kW]	$610	$738	$5,100	$1,521	$1,920	$2,003	$3,203
Annual debt repayment [$/kW/year]	$51	$62	$429	$128	$162	$169	$270
Equity-financed portion [$/kW]	$407	$492	$3,400	$1,014	$1,280	$1,335	$2,136
Annual equity return [$/kW/year]	$65	$79	$543	$162	$204	$213	$341
CCGT LCOE (low) [$/MWh] ($20/ton carbon cost)	$80	Wind FIT 2.0 Contract Price (low) [$/MWh] $105					
CCGT LCOE [$/MWh] ($40/ton carbon cost)	$91	Nuclear Bruce A units 1 & 2 OPA Contract Price (low) [$/MWh] $68					
CCGT LCOE [$/MWh] ($60/ton carbon cost)	$99						
CCGT LCOE [$/MWh] ($80/ton carbon cost)	$108	Nuclear Refurbishment LCOE (high) [$/MWh] ($4,285/kW capital cost) $92					
CCGT LCOE [$/MWh] ($100/ton carbon cost)	$116						
CCGT LCOE [$/MWh] ($120/ton carbon cost)	$125	New Nuclear LCOE (high) [$/MWh] ($6,797/kW capital cost) $138					
CCGT LCOE [$/MWh] ($140/ton carbon cost)	$133						

Notes: LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. Sources: LEI calculations from Energy Velocity commercial database; EIA (2012); OPG (2011); OPA (2012a,g,h); Areva (N.D.); Energie NB Power (2008-2012a,b); Bissett (2012); Hydro Quebec (N.D.); *CNBC (2012)*; and *World Nuclear News*.

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